In recent years technological developments, improved service reliability and increasing tubing diameters have combined to make coiled tubing a preferred technique for many oilfield applications in the Middle East. Coiled tubing offers numerous new possibilities for oilfield management. It can, for example, be used to drill slimhole wells, deploy reeled completions, log high-angle boreholes and deliver treatment fluids.

Coiled tubing has a wide range of potential applications, but it is in drilling that this technology offers the greatest scope for efficient field management. CTD* coiled tubing drilling operations provide cost-effective placement of a wellbore in a reservoir with minimal formation damage, using continuous pipe technology.

David Stein explores the range of CTD tasks and provides examples of successful operations conducted in the Middle East.
Most people think of coiled tubing (CT) as a tool for well workover operations, for example, for cleaning, removing sand, acidizing or logging. However, recent improvements in CT technology and the industry’s continuing drive towards cost-effective operations have opened up new areas of CT operation. CTD coiled tubing drilling has found an important niche in the world drilling market and new technology is continually helping to extend the range of applications.

The first steps in CTD techniques were taken in the 1970s. These experimental drilling operations had mixed results and several technological advances were required to make the technique effective and commercial. Advances in metallurgy made it possible to spool and unspool the tubing repeatedly without causing excessive metal fatigue. The development of larger diameter tubing with greater strength and improved reliability, and the introduction of smaller diameter, positive displacement downhole motors, orienting tools and survey systems, all contributed to the success of coiled tubing drilling.

Reliable commercial CTD operations started in the early 1990s. By the mid-1990s several hundred CTD jobs, conducted with (steered) or without (nonsteered) geosteering techniques, were being carried out around the globe and the jobs performed by Schlumberger reflect that trend (Figure 4.1). Initially, most of the jobs performed with CT were straightforward injection or shallow gas-relief wells. In recent years CT jobs have become more complex: the technique can be used to drill entire wells or multilaterals to several targets.

New software can predict a range of parameters that affect CT operations. These include available weight on the bit, expected pump pressure, wellbore hydraulics and lock-up conditions, which are vital for determining the feasibility of the project.

Applications of coiled tubing drilling

New shallow wells

CT units can be used to drill shallow wells (typically 5000–6000 ft) with diameters of up to 8½ inches. In some soft formations the hole size may reach 13 inches, but the casing will be restricted by the small size of the surface hole.

Coiled tubing is often used to drill slimhole wells with diameters of 5 inches or less. These wells offer good economic and environmental performance, require less consumable materials for completion and produce less waste. Compared to conventional rigs, slimhole drilling setups can deliver wells with fewer people on much smaller sites. This cuts site preparation costs, reduces the environmental impact of onshore drilling operations and reduces the vessel size and space requirements for offshore applications.

Conventional reentry

Deepening and sidetracking existing wells account for most of the jobs conducted in the conventional reentry sector, and CT drilling is suitable for some of these operations. Conventional reentry involves pulling the production string and drilling the well overbalanced or underbalanced. For underbalanced drilling a lightweight or aerated fluid is needed, because any gas-lift mandrels were removed with the completion. These wells are very sensitive to the wellbore configurations with respect to tubing forces and underbalance parameters. When passing through large diameter casing, the weight transfer downhole is severely reduced and, when an aerated fluid is used, slugging effects make it difficult to obtain a steady downhole pressure.

Figure 4.1 Around the world, the number of wells drilled with coiled tubing has risen steadily throughout the 1990s (top). The growth in Schlumberger CTD operations (bottom) has mirrored the global trend...
For sidetrack wells a whipstock is set at the kickoff depth and a window is milled in the casing. Coiled tubing can provide wells up to 6 inches in diameter with build rates up to 30'1000 ft. For horizontal sidetracks the drainhole length, which is usually limited by the required weight on the bit, may reach 4000 ft.

CTD units compete for these jobs against conventional rotary drilling rigs. Low mobilization costs and shorter mobilization periods make CTD jobs economically attractive for reentry work compared with conventional drilling units. Benefits such as underbalance drilling, lower production cost, reduced stimulation costs, and many others, make coiled tubing drilling an attractive alternative to conventional drilling.

Through-tubing reentry

The greatest technical and economic successes for coiled tubing drilling have been in through-tubing reentry operations. The popularity of CT for this application reflects the improved safety and efficiency that it provides. Through-tubing reentries are typically drilled to deepen or sidetrack a well and are performed without removing production tubing (see box: Through the mill). These projects suit CTD methods because no additional surface equipment is needed to pull the tubing. A CT unit can move in to the wellsite, rig up and begin drilling within a few hours. This rapid rig-up capability is especially attractive in offshore and inaccessible locations where drilling and workover rigs have higher day rates.

When combined with the benefits of underbalanced drilling methods, through-tubing reentry drilling projects can provide enormous cost-efficiencies for an operator.

Technical evaluation

The first step in technical evaluation for a CTD operation is to determine how big a hole is required. In through-tubing reentries, the hole size is limited by the internal diameter of the current completion. In new wells and conventional reentries the determination depends on the reservoir parameters and the minimum restriction of the wellbore. For example, it would not be sensible to drill a 10,000 ft lateral section using a 2 1/2-inch bit, nor would it be beneficial to drill a 2000 ft lateral section using a 8 1/2-inch bit when there is 3 1/2-inch tubing in the well.

CTD units compete for these jobs against conventional rotary drilling rigs. Low mobilization costs and shorter mobilization periods make CTD jobs economically attractive for reentry work compared with conventional drilling units. Benefits such as underbalance drilling, lower production cost, reduced stimulation costs, and many others, make coiled tubing drilling an attractive alternative to conventional drilling.

The hole size will dictate the required weight on the bit, the size of motor to turn the bit, the flow rate to clean the hole and the size of the coiled tubing. There are many inter-related variables that affect CTD performance (Figure 4.2). Typically the technical evaluation will be determined in the following order:

- determine the reservoir targets
- determine the hole size based on the reservoir and flow rates
- determine the trajectories and the point and method of kicking off
- based on the hole size and wellbore configuration, determine if the completion can remain in place
- determine the drilling method—overbalanced or underbalanced
- determine the type of drilling fluid—oil-base mud, water-base mud, crudes, nitrogen
- outline the equipment requirements—motor size, type of directional tools, etc
- determine the flow rates required for good hole cleaning within the limitations of the downhole equipment
- determine the CT size based on the circulation pressures, reach and pulling capacities
- refine the process
- outline the surface equipment needed

The technical feasibility is the determination of the cause and effect relationship between the independent and dependent variables which must be considered, particularly when multiphase fluids are involved. Topics such as hole cleaning, weight on-bit and wellbore geometry are studied for their effects on drilling performance. Computer modeling and simulations are powerful tools to complete the study.

Coiled tubing drilling technique

Coiled tubing does not rotate, so hole cleaning and weight transfer benefits attributed to pipe rotation are not realized when drilling with coiled tubing. Conventional drilling practices have been refined to provide effective hole cleaning and weight transfer techniques forcased and openhole operations. Many of the drilling mechanics and hole cleaning problems encountered in early wells can be eliminated with the use of low-solids muds or underbalanced drilling.

<table>
<thead>
<tr>
<th>Independent variables</th>
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<tr>
<td>CTD variables</td>
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<tr>
<td></td>
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<tr>
<td>Motor performance</td>
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<tr>
<td>Rate of penetration</td>
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<td>Hole cleaning</td>
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<tr>
<td>Bottomhole pressure</td>
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<tr>
<td>Wellbore stability</td>
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<tr>
<td>Cost</td>
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<tr>
<td>Formation damage</td>
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<tr>
<td>Pump pressure</td>
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<tr>
<td>Weight on the bit</td>
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</table>

1 Liquid flow rate
2 Gas flow rate
3 Foamed versus nonfoamed fluid
4 Liquid phase type/additives
5 Hole size
6 Casing geometry (size weight)

7 Motor configuration
8 Bit type
9 String weight (hook load)
10 Build rates/doglegs
11 CT size/weight/grade

Figure 4.2 CTD variables (motor performance, rate of penetration, etc) are influenced by independent variables (liquid flow rate, hole size, etc) as shown.
Satisfactory drilling rates with coiled tubing or rotary drilling require adequate transfer of weight to the bit. Conventional rotary drilling relies primarily on the use of drill collars, sometimes located in the vertical sections for horizontal wells, to supply weight to the bit. Rotation of the drillstring improves weight to the bit by reducing the effective wall contact friction. This follows the classical friction theory; the friction force vector opposes the direction of the resulting velocity vector. Weight transfer for coiled tubing drilling is accomplished primarily by pushing on the resilient coiled tubing string in the horizontal sections. Coiled tubing is less rigid than drillpipe and helical buckling and eventually ‘lock-up’ will occur as the coiled tubing compressive force is increased. Only a small percentage of string weight can be transferred to the bit, because of the high coefficient of friction associated with slide drilling; friction factors can be in the range 0.40–0.65, compared with factors of less than 0.10 in rotary drilling.

Cutting beds reduce weight transfer and can result in differential sticking. Frequent short trips are used to remove cutting beds which accumulate around the coiled tubing in deviated and horizontal sections. Short trips to the start of the build section or the casing window are performed after each 50–100 ft of new hole. Extended short trips to the tubing tail to remove cuttings from the large casing are sometimes needed for through-tubing applications where the hole size increases in the casing. The maximum flow rate available for hole cleaning with CT is limited by the pressure at the surface and the flow rate limitation of the downhole motor/bottomhole assembly (BHA).

Perfectly underbalanced

In underbalanced drilling wellbore pressure is lower than the pressure of the formation being drilled. This induces a continuous flow of formation fluids into the hole as drilling progresses and minimizes or eliminates formation damage. Reduced damage can increase production, provide earlier payout and lower well stimulation costs, compared with overbalanced wells.

The most important part of an underbalanced CTD campaign is candidate recognition. The selection process is typically performed by the client in conjunction with specialist teams. Once the candidate wells have been chosen, a range of Schlumberger service providers can be brought together to pool their expertise and execute the integrated project. Only computer modeling can handle all of the variables that the driller will encounter in underbalanced coiled tubing drilling.

Underbalanced drilling can also help to improve drilling performance by increasing rate of penetration, eliminating severe lost circulation and preventing differential sticking. It is particularly suitable for horizontal wells where the pay zone is exposed to drilling operations for long periods of time.

Although underbalanced drilling jobs can be conducted with jointed pipe systems, such as snubbing units, they are safer and more efficient when CT methods are employed (Figure 4.3). CT is a continuous conduit with no external connections and this offers a safer underbalanced package than conventional drilling rigs. Underbalanced coiled tubing drilling allows geoscientists to assess the productivity of each section as it is drilled.

### Underbalanced drilling

<table>
<thead>
<tr>
<th>Conventional drilling rig</th>
<th>Coiled tubing drilling</th>
</tr>
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<tbody>
<tr>
<td>• Disruption of flow when making connections and during tripping</td>
<td>• Safe option: no personnel required at wellhead during drilling or tripping</td>
</tr>
<tr>
<td>• Downhole pressure fluctuations</td>
<td>• Reduced downhole pressure fluctuations</td>
</tr>
<tr>
<td>• Surface pressures limited to 1500 psi</td>
<td>• Reduced trip times</td>
</tr>
<tr>
<td>• Long connection and trip times</td>
<td>• Bottomhole assembly can be deployed in a live well</td>
</tr>
<tr>
<td></td>
<td>• Internal wireline can be installed for real-time measurement</td>
</tr>
</tbody>
</table>

Figure 4.3 For underbalanced drilling operations the CTD method is a safer and less expensive option than conventional rotary drilling methods.

### Through the mill

One of the most attractive markets for CTD jobs is through-tubing reentry wells. One reason for this is that the CTD technique provides a very successful method for exiting the wellbore. Most of the growth in reentry drilling was made possible by the rapid developments in whipstock and cement milling techniques. These innovations are the results of extensive testing to select the proper equipment and refine the technique.

Whipstock, or window, milling involves cutting a hole or ‘window’ in the casing and/or tubing with a downhole motor and mill. The mills are nonaggressive to reduce motor stalling and create a smooth exit path through the tubulars. As the window milling progresses, the metal cuttings are weighed at surface. Typically 50–80% of the theoretical weight of metal is recovered at surface (Figure 4A.1). This will give an indication when problems occur. Also, traces of cement and formation solids will start appearing in the returns as the assembly moves out of the tubular.

In Alaska, Arco completed more than 65 reentry sidetracks at 50–75% of the cost of drilling a new well. The company documented its drilling program and analyzed performance in detail. This careful analysis led to a 25% reduction in total sidetracking time.

Wells included in the program were typically constructed with 13 3/4-inch surface casing, 9 5/8-inch intermediate (production) casing, 7-inch production liner and 4 1/2- or 5 1/2-inch tubing. A 9 5/8-inch permanent packer was typically set just above the 7-inch liner with an optional isolation packer in the liner.

The kickoff method used in Alaska consisted of setting a fiber-reinforced cement plug below the tailpipe and inside the 7- or 9 5/8-inch casing. A pilot hole was drilled into the cement plug. Initially the hole was oriented to the low side for approximately 15 ft. After drilling with the low-side setting, the tool was oriented to the high side in order to build up angle before contacting the opposite casing wall. The hole path passes the highest contact angle between the bottomhole assembly and casing wall, which increases the success of milling through the casing. If the angle is not high enough the milling assembly will slide down the casing wall without exiting. Once the mill contacts the casing wall a time drilling process starts. The time drilling process allows the mill to gradually cut into the casing without rolling off the path (Figure 4A.2).
Figure 4A.1 The first step in drilling lateral boreholes from existing vertical wells is to mill a hole or ‘window’ through the casing in the vertical well before a whipstock is run into the hole to guide the drill bit out of the vertical well. Precision milling can be a complex and time-consuming process but it is essential for many CTD operations. The quantity of metal milled can be estimated using a simple formula (below). This estimate is compared with the total weight of metal returned to surface by mud circulation.

\[ a = \frac{BD}{2}/\sin\phi = 42.99 \text{ inches} \]
\[ b = BD/2 = 1.875 \text{ inches} \]
\[ \text{Area of hole(parabolic)} = \frac{4}{3}ab = 107.46 \text{ inches}^2 \]

Volume of metal:
\[ Wt = (T_{csg} + T_{tbg}) \times (2 \times \text{area}) \times \text{Den} = 90 \text{ lb} \]

<table>
<thead>
<tr>
<th>Symbols</th>
<th>Description</th>
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<tbody>
<tr>
<td>( \phi )</td>
<td>angle of whipstock</td>
</tr>
<tr>
<td>WL</td>
<td>window length</td>
</tr>
<tr>
<td>( T_{csg} )</td>
<td>casing thickness</td>
</tr>
<tr>
<td>( T_{tbg} )</td>
<td>tubing thickness</td>
</tr>
<tr>
<td>BD</td>
<td>bit diameter</td>
</tr>
<tr>
<td>Den</td>
<td>steel density</td>
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Values

\[ \phi = 2.5^\circ \]
\[ WL = 2a \]
\[ T_{csg} = 0.937 \text{ inches} \]
\[ T_{tbg} = 0.542 \text{ inches} \]
\[ BD = 3.75 \text{ inches} \]
\[ \text{Den} = 0.284 \text{ lb/inch}^3 \]
Over and under in Oman

A recent CTD campaign in Oman involved drilling 15 onshore wells for Petroleum Development Oman (PDO) (Figures 4.4 and 4.5). The campaign was divided into two parts:

- overbalanced reentries where the completion had been removed
- underbalanced through-tubing drilling

In the 11 wells that comprised the overbalanced reentry operation, the completion was pulled out of the well before setting the whipstock. Once the whipstock had been set, a window was milled through the 7-inch or 9 5/8-inch casing where a 6 1/8-inch buildup section was drilled. After landing the buildup section, a 4 1/2-inch liner was run with coiled tubing and cemented in place. The lateral was then drilled with a 3 3/4-inch bit and completed barefoot.

After completing 11 overbalanced wells, the remaining four in the campaign were completed underbalanced. These wells took advantage of the through-tubing application, passing through 4 3/4-inch tubing containing gas-lift mandrels. The gas-lift mandrels were used to achieve the underbalanced conditions. The wells were allowed to flow throughout the entire operation, including installation and removal of the BHA from the live well. This was
accomplished by the use of a deployment lubricator. The deployment lubricator was approximately 70 ft in length, sufficient to cover all of the BHA’s (Figure 4.6).

The drilling performance in the underbalanced wells substantially improved compared to the previous overbalanced wells. Overall, the benefits from the underbalanced drilling campaign included:

- a rate of penetration (300 ft/hour) that was 10 times faster than in wells drilled with overbalance
- improved hole cleaning; fewer and shorter wiper trips
- more weight transferred to the bit
- continuous well flow during the operations
- low circulation pressure
- improved coiled tubing life (lower circulation pressure, fewer short trips)

**Fateh laterals**

This well was originally completed to produce oil from a lower formation. When the well had to be permanently shut in as a result of high water cut, the managers decided to sidetrack it. This involved drilling a 3 ¾-inch openhole horizontal well in the overlying formation (Figure 4.7). The producing targets in this formation, the upper and lower porosity intervals, are separated by about 30 ft of dense, low-permeability limestone, so two separate laterals were required.
The well was drilled as a dual lateral openhole completion sidetracked from the existing wellbore (Figure 4.8). The upper lateral was drilled with a build rate of $40^\circ/100\text{ ft}$ for a total depth of 10,600 ft measured depth (MD) and a lateral displacement of 2054 ft in the upper porosity interval. The lower lateral leg was sidetracked from the wellbore of the upper leg at a depth of 8400 ft (MD) at an inclination of $41^\circ$. This leg was kicked off from the existing openhole by orienting the bent sub to the low side of the hole and time drilling. The lower leg was drilled to a total depth of 10,500 ft (MD), achieving a lateral length of 1700 ft in the lower porosity interval.

Both laterals were drilled overbalanced and stimulated with a 28% solution of hydrochloric acid. A special bent sub and measurement-while-drilling (MWD) methods were used to selectively guide the tubing into the laterals for stimulation. The total measured depths of the laterals were specifically planned to be different. This would allow the engineers conducting the workover to determine into which of the two lateral holes the stimulation tool had been run.

For acidizing, the downhole assembly (Figure 4.9) was oriented to the high side of the well and run to total depth. The depth was confirmed to ensure that the coiled tubing was in the upper lateral leg before the stimulation procedure began. Before any acid was released, the assembly was rotated until the tool was directed towards the low side of the well. This was done to ensure that the assembly could be run into the lower lateral for the second phase of the acidizing operation.
The upper lateral was stimulated back to a depth 200 ft below the junction. Acidizing was stopped there to prevent erosion of the formation at the junction between the laterals. With the tool face still pointed to the low side of the hole, the assembly was tripped into the lower lateral. Depth checks were conducted to confirm that the sub had entered the correct hole and the lower leg was acidized to a point 200 ft from the junction (Figure 4.10).

**Downhole control: the key to CTD efficiency**

To be effective, CTD systems must draw upon and improve the best coiled tubing and rotary drilling technologies. In CTD operations the tubing does not rotate and a mud motor is required to turn the bit. The driller must be able to orient the bit quickly and accurately and the system must emulate rotary drilling for optimum rates of penetration and straight well paths.

A CTD system must perform well in aerated fluids during underbalanced drilling. It must be able to measure pressures downhole to optimize mud-motor performance, ensure the underbalanced conditions are maintained to protect the formation and ensure wellsite safety. The system must be capable of transmitting data in the presence of aerated fluids and must maintain depth correlation while in the casing or during drilling. Reliable, accurate directional survey data and the ability to conduct formation evaluations are also essential requirements.
The next generation

The VIPER* slimhole CTD MWD and motor system (Figure 4.11) provides real-time drilling information, precise orientation control and pressure sensors to monitor bottomhole pressure. The VIPER system is a wireline-controlled bottomhole assembly (BHA) that consists of a downhole orienting tool for directional control and an MWD system for directional measurements. Orienting-while-drilling ensures accurate, continuous directional control. The VIPER system uses an electromechanical orienting tool that rotates in either direction, continuously or in 1° increments, to control the wellpath. Fine downhole adjustments can be made in real time by inputting the desired toolface corrections into the surface computer of the VIPER systems.

Straight and smooth

The slow, continuous rotation of the VIPER tool enables it to drill boreholes that are straighter and smoother than can be achieved with conventional methods. Generating up to 1000 ft-lbf torque, the VIPER tool rotates at 1 rpm to eliminate the effect of the fixed-bend motor. The straighter wellbore provides:

- faster penetration rates
- reduced drag and longer reach
- easier running of completions
- more efficient workover operations
- better hole cleaning

Staying on track

Using gamma ray and casing collar locator sensors, drillers can reduce the depth discrepancies often encountered in CT operations. These discrepancies are usually caused by buckling of the CT as it is pushed into the wellbore. The gamma ray sensors of the VIPER system identify formations, or horizons within them, for reliable depth correlation. The casing collar locator sensor is also useful during reentry drilling for accurate depth control (Figure 4.12).

The VIPER system BHA can be oriented while drilling. Fine downhole adjustments are possible by inputting the desired toolface corrections into the surface computer system. The orienting tool’s ability to turn continuously allows the driller to rotate and slide while drilling curves and laterals, resulting in faster rates of penetration and less tortuous well paths.

Linked to the orienting tool is a reliable and robust directional surveying package. Azimuth, inclination and toolface measurements are transmitted to the surface through its high data rate wireline telemetry system to give the driller more control for sophisticated well paths and tighter targets.

The tool’s gamma ray sensor can be used for geological correlation. This allows a simple form of geosteering to increase the accuracy of the well path. Some geological interpretation is possible and the gamma ray sensor can be used to recognize marker formations and so aid depth correlation.

Pressure control

The VIPER system logging module uses advanced pressure sensor technology to monitor internal (CT) and external (annular) pressure during drilling, tripping and circulating the well. When drilling underbalanced wells with a gasified liquid fluid, the annular pressure sensor allows greater control of the hydrostatic pressure acting on the reservoir. This helps the driller to avoid killing the well and damaging the formation by fluids or solids invasion. The pressure sensor measurements are also used to keep the motor running at peak performance for maximum penetration rates, and to prevent stalling.
Working with the wireline

Using a wireline system for data transfer means that the VIPER tool can transmit high data volumes much faster than systems that rely on mud-pulse transmission. Drilling information, for example, can be transmitted at rates of around 100,000 bits per second in the VIPER system wireline, compared to only 3–6 bits per second in mud-pulse transmission.

Wireline telemetry can transmit data to the surface regardless of the drilling fluid being used. Data are transmitted equally well in underbalanced or overbalanced conditions. The data rates are very high, giving the driller almost real-time information from the sensors. Because data transmission is instantaneous, no time is lost waiting for mud pulses to be established. The high data-transmission capacity of the wireline will allow the addition of other LWD tools to the BHA in the future.

Built-in benefits

The VIPER system is an integral part of the CTD system. Designed to work in a wide range of temperatures and pressures, its sensors can withstand the high shock environment encountered at the bit. The wireline telemetry system works in all fluids and can transmit real-time sensor and control data, increasing the engineer’s control over the drilling process.

The orienting tool will bring the greatest benefits to the CTD process. The tool’s orientation can be continuously adjusted to allow well paths to be drilled to closer tolerances. Precise corrections and changes to the toolface orientation can be made while drilling to avoid nonproductive time. Continuous rotation of the VIPER BHA adds a rotary capability to improve drilling performance and the control over the well path. By integrating the BHA into the CTD process, the efficiency of the whole operation has been increased.
Coping with cuttings

The traditional guidelines for hole cleaning using unweighted, unviscosified fluids are a minimum annular velocity of 50 ft/min in vertical holes and 100 ft/min in horizontal holes. These values are lower than would normally be applied in conventional drilling due to the high downhole motor rpm and low weight on the bit, resulting in smaller cuttings with coiled tubing drilling.

There are two major points that differentiate hole cleaning in CT drilling operations from hole cleaning in conventional rotary drilling:

- In rotary drilling the drilling fluid must be able to support the cuttings when the pumps are switched off while making a connection: in CT drilling, shutting down flow is infrequent
- In rotary drilling the rotation of the drillpipe contributes to hole cleaning by continually entraining the cuttings back into the mainstream from the lower side of the hole: in CT drilling the pipe does not rotate above the motor

These differences are substantial and call for new techniques for designing fluids for CT drilling. Thus the central requirement for rotary drilling— a high yield stress— is neither necessary nor sufficient in CT drilling.

A recent study\(^1\) of cuttings transport in CTD wells showed that hole cleaning is more efficient if a low-viscosity fluid is pumped in turbulent flow rather than a high-viscosity fluid in a laminar flow. Hole cleaning with a viscous fluid in a laminar flow is inefficient because of the fluid’s inability to pick up the cuttings on the low side of the hole; with conventional drilling the rotation of the string is used to agitate the cuttings beds and introduce the solids into the flow path. To achieve turbulent flow requires higher pumping rates, which are limited by the circulation pressure of the tubing and flow rate through the downhole equipment.

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The fluid’s inability to clean the hole means that alternative methods must be applied. One way to help solve the hole cleaning problem is the use of wiper trips. A wiper trip simply involves pulling the BHA back to a selected point and then redrilling as necessary back to the bottom of the hole. Wiper trips may be required for numerous operational reasons unconnected with hole cleaning, but the ability to circulate while running in-hole or pulling out of hole can help to resolve cuttings transport problems. In addition to the traditional drilling methods of monitoring drag and returns, the CTD technique uses an annular pressure measurement to monitor trends in annulus loading. When cuttings beds are encountered, possible solutions include:

- progressive wiper trips: with coiled tubing drilling more wiper trips are required as a substitute for rotation and to monitor bed buildup behind the BHA
- raking the low side of the borehole to clear cuttings from low spots: the bent sub is oriented down towards the low side of the hole and the bit is worked up the hole rather than down

Cuttings beds often develop in the build section even when the horizontal section of the wellbore is clear. The driller must be careful, when pulling into the build section, not to wedge the BHA in the cuttings bed and risk it becoming stuck.

When pulling out of hole, the bit will shift the cuttings up the hole. Cuttings from the wiper trip will accumulate as shown in Figure 4.13. This means that the cuttings bed will reach maximum thickness just above the bit and may cause sticking. Once the cuttings have formed a bed, only the bit or turbulent flow can move them.

When running into the hole, the higher annular velocity caused by metal displacement may clean more effectively if it results in turbulent flow. However, if the flow is laminar, the cuttings will fall out as shown in Figure 4.14.

In underbalanced wells with large inflow, sections of more than 1000 ft have been drilled without a wiper trip. The inflow, which may nearly double the annular velocity, helps to stir up cuttings from the bed and provides more turbulent mixing to help keep them in suspension. Cuttings from underbalanced drilling are generally larger than those from overbalanced wells but the inflow means that this is not usually a problem.

Several underbalanced wells drilled to date have shown no signs of hole cleaning problems, but problems have been encountered in the build section. This is probably because there is no inflow in the build section to stir up the cuttings beds that form there.

If the hole cannot be cleaned with turbulent flow the simple estimation of cuttings transport distance will allow the driller to base wiper trip design on easily calculated parameters rather than a ‘best guess’. Fewer short trips and less viscous muds are both potential cost reducers. Even if the number of short trips remains the same, a less viscous mud will provide lower pump pressure and direct savings as a result of increased CT life.

Conclusions

Successful CTD operations call for close cooperation from experts in a number of disparate technical disciplines. Without the right combination of drilling, logging, well engineering, testing and software skills no CTD operation could succeed. For underbalanced or just-balanced drilling, through-tubing drilling or conventional slimhole reentry, the CTD technique is an alternative to conventional drilling. As CTD technology improves and its environmental benefits are more widely recognized, the range and number of drilling operations conducted with coiled tubing looks certain to increase.